BEFORE
THE PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA
DOCKET NO. 2020-263-E – ORDER NO. 2021-__

_______________, 2021

Cherokee County Cogeneration Partners, LLC Complainant, v. Duke Energy Progress, LLC and Duke Energy Carolinas, LLC, Respondents.	))))))))))	**ORDER RULING ON COMPLAINT**

I. INTRODUCTION

This matter is before the Public Service Commission of South Carolina (the "Commission") on the Complaint and Request for Interim Relief ("Complaint") of Cherokee County Cogeneration Partners, LLC ("Cherokee" or "Complainant") filed on November 2, 2020. The Complaint named Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC") (together "Duke Parties") as Respondents. The South Carolina Office of Regulatory Staff ("ORS") was a party of record in the case pursuant to S.C. Code Ann. § 58-4-10(B) (2015).

II. BACKGROUND

The Cherokee Facility is a 98 MW combined cycle cogeneration power generating qualifying facility ("QF") located in Gaffney, South Carolina (the "Cherokee Facility" or the "Facility"). (Tr. Vol. 2, pp. 242.5-6). Cherokee either employs or supports or supports the employment at its site of about 50-75 people operating the power facility on a year-round basis..

(Tr. Vol. 1, p. 78). DEC purchases energy and capacity from Cherokee pursuant to a power purchase agreement ("PPA") executed on June 28, 2012 for a 7 year term commencing January 1, 2013 (the "2012 Agreement"). Tr. Vol. 2, p. 242.7. The 2012 Agreement is structured as a dispatchable tolling agreement whereby DEC provides the fuel and dispatches the Facility in return for a fixed monthly payment to Cherokee consistent with DEC's avoided costs under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). *Id.*

III. PROCEDURAL HISTORY

Cherokee was represented by John J. Pringle, Jr., Esquire, William DeGrandis, and Jenna McGrath, Esquire. DEC and DEP were represented by Frank R. Ellerbe, III, Esquire, Brett B, and Tracy DeMarco. ORS was represented by Jenny Pittman, Esquire and Jeff Nelson, Esquire.

On November 2, 2020, Cherokee filed its Complaint and Request for Interim Relief. On November 30, 2020, Cherokee requested that the Commission hold oral argument on Cherokee's Request for Interim Relief. On December 8, 2020, DEC and DEP filed their response to Cherokee's Request for Interim Relief. On December 10, 2020, the Commission held oral argument on Cherokee's Request for Interim Relief. On December 30, 2020, the Commission issued its Order Granting Temporary 120-Day Extension of Agreement and Other Matters, Order 2020-846, extending the PPA between Cherokee and DEP for a period of one hundred and twenty (120) days, and instructing the parties to conduct mediation. On February 26, 2021, the parties participated in a mediation, but were unable to reach agreement on the issues in dispute. The parties also conducted written discovery.

On April 9, 2021, Cherokee requested that the Commission further extend the term of the PPA. On April 20, 2021, the Duke Companies filed a letter in response to Cherokee's request to further extend the term of the PPA, advocating that any "such extension should be for a limited, definite period of time and should be subject to a true-up upon the conclusion of this proceeding." On April 21, 2021, the ORS also filed a letter objecting to any further extension of the term of the PPA unless the Commission determined that the rates charged and paid according to the PPA during the extensions are subject to a true-up. On April 28, 2021, the Commission issued its Order Extending the Agreement with True-up Option Between Parties until August 28, 2021, Order No. 2021-294, extending the term of the PPA until August 28, 2021 or upon issuance of a final order on the merits of the case, whichever occurs first.

Cherokee prefiled (and subsequently presented) the testimony of Nathan Hanson (direct and rebuttal testimony) and Kurt Strunk (direct and rebuttal testimony).

The Duke Companies prefiled (and subsequently presented) the direct testimony of Michael Keen, John Freund, Kendall Bowman, and Glen Snider.

ORS prefiled (and subsequently presented) the direct testimony of Dawn Hipp.

The Commission conducted a virtual evidentiary hearing in this matter on July 26, 2021, July 29, 2021, and July 30, 2021, with the Honorable Justin T. Williams presiding.

IV. GUIDING LEGAL FRAMEWORK: PURPA AND ACT 62

A. Jurisdiction

The Commission, as the State regulatory agency with oversight and ratemaking authority, has jurisdiction over the instant matter, as the Respondents are electric utilities pursuant to South Carolina law. *See* S.C. Code Ann. § 58-27-10, *et seq*. PURPA utilizes a cooperative federalism model by which the Federal Energy Regulatory Commission ("FERC") prescribes rules regarding all aspects of rates, terms, and conditions for sales of electric power to, and purchases of output from, cogeneration and small power production (collectively, "Qualifying Facilities" or "QFs"). Each state establishes rules for implementing PURPA, within the regulatory guardrails adopted by FERC, and adjudicates disputes over the application of the FERC and state PURPA rules, with regard to rates, terms and conditions of service.

South Carolina's Act 62 effectuates the Commission's state-wide PURPA regulations. *See* S.C. Code Ann. § 58-41-20(A) (requiring that Act 62's implementation by the Commission must be "consistent with PURPA and the Federal Energy Regulatory Commission's implementing regulations and orders, and nondiscriminatory to small power producers . . . . "). Accordingly, Cherokee's Complaint seeks resolution of all unresolved terms and conditions necessary to establish a PPA between Cherokee and Respondents pursuant to PURPA and FERC's and the Commission's regulations and orders.

B. PURPA Framework and Mandatory Purchase Requirements

PURPA, the first federal law of its kind, was designed to encourage cogeneration and small power production, by requiring utilities to purchase electric power from QFs at rates that are just and reasonable, in the public interest, and not discriminatory. *See* 16 U.S.C. § 824a-3(a); s*ee also* Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69, FERC Stats. & Regs., 45 Fed. Reg. 12214, 12215 (1980)("Order No. 69"). Prior to the enactment of PURPA, cogenerators and small power producers faced barriers that Congress sought to eliminate; among them, 1) utilities were not required to purchase the output from these facilities, 2) utilities were not required to do so at fair rates, and 3) utilities could charge discriminatory and unfair charges to back up power and interconnect a facility to the grid. Order No. 69, FERC Stats. & Regs., 45 Fed. Reg. at 12215. Congress, and FERC through its implementing rules, addressed these obstacles; requiring utilities to purchase the output of the QFs, and adopting rules for interconnection rates and terms. *Id*.

As a means of encouraging QFs, Respondents, as electric utilities, are required to interconnect with, and purchase electric power from, QFs at rates that are just and reasonable, in the public interest, and non-discriminatory. *See* 16 U.S.C. § 824a-3(a); *see also* Order No. 69, FERC Stats. & Regs., 45 Fed. Reg. 12214, 12215 (1980). Avoided cost rates are just and reasonable, in the public interest and non-discriminatory under PURPA. *See Conn. Light and Power Co.*, 70 FERC ¶ 61,012, 61,023-24 (1995) (*citing* 18 C.F.R. § 292.304(b)(2) (1994)) (asserting that "a rate for purchases from a [QF] will be considered to be just and reasonable and in the public interest and also not discriminatory 'if the rate equals…avoided costs'."). Under PURPA, the rates to QFs mandated under PURPA must not exceed the purchasing utility's "avoided costs," defined as "the cost to the electric utility of the electric energy which, but for the purchase from such [QF], such utility would generate or purchase from another source." 16 U.S.C.A. § 824a-3(d).

For QFs above 2 MW in South Carolina, where avoided cost rates are not based on a standard offer, *See* S.C. Code Ann. § 58-41-10(15), the Commission must take into account factors prescribed by FERC in determining avoided cost. FERC's regulations implementing PURPA require that state commissions, when determining avoided costs, must take into account factors relevant to this case; (1) availability of capacity or energy as it relates to (a) dispatchability, (b) reliability, and (c) terms, including duration, of any contract or other legally enforceable obligation; and (2) relationship of the available energy or capacity with the ability of the utility to avoid costs. *See* 18 C.F.R. § 292.304(e)(2).

The QF, not the utility, has the option to commit itself to sell either all or part of its electric output to a utility through a contract or through a legally enforceable obligation (LEO). 18 C.F.R. § 292.304(d). As such, a utility cannot unilaterally nullify or rescind a LEO. Relatedly, it is the state Commission, not the utility, that determines whether a LEO was established in the first place, consistent with FERC's LEO requirement discussed further below.[1] A LEO should be of sufficient duration so as to attract potential investors for the QF. *See Windham Solar LLC*, 157 FERC ¶ 61,134, 61,476 (2016). The rates for purchases may be based, at the option of the QF, either 1) on avoided costs calculated at the time of delivery or 2) on avoided cost rates projected at the time the obligation is incurred. 18 C.F.R. § 292.304(d)(1)(ii)(A-B).

When FERC issued proposed rules permitting QFs to establish a LEO and base their avoided costs based on rates projected at the time of the LEO, rather than at the time of delivery, some commenters objected, arguing that if the avoided cost at the time of delivery turned out to be less than the rates provided in the contract or under the LEO, that the QF would be subsidized at the expense at the expense of the utility's ratepayers. Order No. 69 FERC Stats. & Regs., 45 Fed. Reg. at 12224. FERC recognized that possibility, but noted that in other cases, the contract or LEO rate may be less than the avoided costs at the time of delivery. FERC has clarified through its regulations that avoided cost rates established via a LEO do not violate PURPA's requirement that a utility pay no more than its avoided costs to a qualified facility: "In the case in

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1 *See* Hearing Exhibit 18; see also *infra* p. [20].

which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery." 18 C.F.R. § 292.304(b)(5).

The purpose behind FERC's creation of the LEO was to further the federal balance struck between utility and QF interests: the LEO provides protection to QFs by preventing utilities from circumventing their PURPA obligations through delayed signings of a contract to benefit from a lower avoided cost, and splits the risk of over- or under-payment of avoided costs between the consumer and the QF. Order No. 69, FERC Stats. & Regs., 45 Fed. Reg. 12,224; *see Deseret Generation & Transmission Coop., Inc.*, 175 FERC ¶ 61,041, P 19 (2021) (citing *Cedar Creek*, 137 FERC ¶ 61,006, at P 36 (citing *W. Penn Power Co.*, 71 FERC ¶ 61,153 at 61,495) (1995)).

While FERC's regulations do not prescribe a specific test that states can use to determine whether a LEO is established, FERC has clarified that there are certain limitations on the creation of a LEO that are inconsistent with PURPA. For example, FERC has recognized that it is the QF's actions to sell to an electric utility that commits the electric utility to buy from that QF, and thus LEO requirements may not depend on action from the utility. *See JD Wind 1, LLC*, 129 FERC ¶ 61,148, 61,633 (2009); *See also FLS Energy, Inc.*, 157 FERC ¶ 61,211, 61,730-31, (2016). Accordingly, states may not require a fully executed contract, facilities study, or an interconnection agreement in determining the existence of a LEO. *See Cedar Creek*, at 61,024 (citing Order No. 69,FERC Stats. & Regs., 45 Fed. Reg. at 12,224 (1980)); *See also FLS Energy, Inc.*, 157 FERC ¶ 61,211, 61,730 (2016). Placing the onus solely on the QF to commit itself to sell electric output to a utility furthers the intent of PURPA by preventing utilities from avoiding their obligations through the use of tactics to achieve a lower avoided cost by procurement of power from, or construction of, alternative resources. However, states may give effect to FERC's rules, taking action under PURPA through the issuance of regulations, resolution of disputes, or other action. *FERC v. Miss*., 456 U.S. 742, 751 (1982); *see* Policy Statement Regarding the Commission's Enforcement Role Under Section 210 of the Public Utilities Act of 1978, 23 FERC ¶ 61,304, at 61,644 (1983).

PURPA requires a utility like DEC to buy all the energy and capacity of a qualifying facility like Cherokee (as they have done for over two decades to date). As a result, the Power Purchase Agreement (or means of purchase and sale) is an arrangement that the utility *has to* negotiate with a QF, as opposed to a typical commercial agreement where the parties *want to* negotiate. Therefore, it is not surprising that at times the utility has a somewhat different view than the qualified facility of what negotiation requires in the PURPA context, and negotiation disputes end up before the Commission.

Indeed, the Commission has observed the "possibility of problems that may exist in the negotiation of long-term contracts" between utilities and qualified facilities.[2] Accordingly, while the Commission "urges voluntary negotiation of long-term contracts" between utilities and qualified facilities, in the very same breath (or sentence) the Commission "points to the complaint procedure available through the Commission as a proper forum to resolve any disagreements" between a utility and a qualified facility.[3] Hence the Commission's historical and ongoing role in hearing disputes between utilities and qualified facilities.

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2 Order No. 85-347, p. 20.

3 *Id*. at 21.

In fact, PURPA's requirement to negotiate—and allegations of a lack of good faith negotiation -- have been addressed in more than one Commission order addressing a PURPA dispute between a utility and a qualifying facility. For example, in Docket No. 80-251-E, the Commission granted "extraordinary interim relief" (via Order No. 85-37) based on unreasonable conduct by a utility (Duke Power) in negotiations with a qualifying facility (Aquenergy Systems, Inc.). The Commission further observed that the need for extraordinary interim relief "indicates that perhaps more emphasis on good faith needs to be placed in the negotiations.[4]Further, the Commission has considered various tools (e.g. assessing costs against an "unreasonable party") "to encourage good faith negotiations between qualifying facilities and electric utilities if complaints are received by the Commission or the Commission Staff indicating a lack of good faith negotiations by either party."[5]

There is no definition of "good faith" found in PURPA. However, Section 58-41-20(F)(1) of Act 62 requires utilities to "offer into fixed price power purchase agreements with small power producers for the purchase of energy and capacity at avoided cost, with *commercially reasonable terms* and a duration of ten years." (Emphasis added). The requirement to offer power purchase agreements with "commercially reasonable terms" is therefore an element of good faith negotiation. Similarly, South Carolina law defining the "obligation of good faith" makes clear that parties must also observe "reasonable commercial standards of fair dealing" in their negotiations of power purchase agreement. Section 11-35-30 of the South Carolina Consolidated Procurement Code, entitled "Obligation of good faith,"

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4 *Id*. at 19.

5 *Id*. at 20.

provides the following: "Good faith means honesty in fact in the conduct or transaction concerned and *the observance of reasonable commercial standards of fair dealing*." (Emphasis added).

In sum, PURPA requires that utilities offer qualified facilities power purchase agreements with "commercially reasonable terms," and observe "reasonable commercial standards of fair dealing" in their negotiations with qualified facilities.

C. Act 62 Requirements

Act 62 sets forth the Commission's regulations for implementing PURPA in South Carolina, recognizing the balance PURPA strikes between the promotion of QFs and risks for consumers. The framework set forth in Act 62 requires consistency with PURPA, which is achieved in part through requirements mirroring FERC's regulations through a consistent definition of avoided cost and the express requirement for just and reasonable rates, in the public interest, that are not discriminatory towards QFs. *See generally* S.C. Code Ann. § 58-41-20(A).

In furthering PURPA's policy objectives, Act 62 requires electric utilities to offer 10-year fixed price power purchase agreements from QFs at the electric utility's avoided cost. S.C. Code Ann. § 58-41-20(F); *See Amended Order Approving Duke Energy Carolinas, LLC's and Duke Energy Progress LLC's Standard Offer Tariffs, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, and Commitment to Sell Forms*, Order No. 2019-881(A), January 2, 2020 at p.28 ("Order No. 2019-881(A)"). Avoided costs for QFs above MW are calculated based on the most recent avoided cost methodology approved by the Commission. S.C. Code Ann. § 58-41-20(C). The terms and conditions of the fixed price power purchase agreements must be "commercially reasonable." S.C. Code Ann. § 58-41-20(F)(1).

Under South Carolina law, QFs have the right to demonstrate their commitment to sell the output of their facility to an electric utility through a notice of commitment form. *See* S.C. Code Ann. § 58-41-20(D); *see also* Order No. 2019-881(A), at 140. Relatedly, and in line with FERC precedent, Act 62 expressly states that a power purchase agreement is not required to demonstrate the presence of a LEO. S.C. Code Ann. § 58-41-20(D).

Disputes under Act 62 may be resolved by the Commission through a formal complaint proceeding. S.C. Code Ann. § 58-41-20(C).

V. FINDINGS OF FACT

Based on the testimony and exhibits received into evidence at the hearing and via late-filed exhibits, and the entire record of these proceedings, the Commission hereby makes the following findings of fact:

A. Legally Enforceable Obligation

1. The purpose of the non-contractual LEO, as FERC set forth in Order No. 69, is "to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility." Order No. 69, FERC Stats. & Regs., 45 Fed. Reg. at 12,224 . FERC's concern occurred in this case.

2. This Commission's Order No. 2016-349 was the effective law as of September 17, 2018. It stated the following: "All *rates* for QFs above two MW, or otherwise ineligible for the standard tariffs, *shall be negotiated* under the Public Utility Regulatory Policies Act of 1978 and the Federal Energy Regulatory Commission's implementing regulations." Order Approving Revised Schedules PP (SC) Purchased Power and PP Purchased Power, and Terms and Conditions for each as Proposed by Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Public Service Commission of South Carolina, Order No. 2016-349, pp.1-2 (Order No. 2016-349) (emphasis added).

3. FERC's orders have provided general guidance that "a QF, *by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF*; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations." *JD Wind 1, LLC*, 129 FERC ¶ 61,148, 61,633 (2009) (emphasis added).

4. FERC has also recently made clear that "the establishment of a legally enforceable obligation turns on the QF's commitment, and not the utility's actions." *FLS Energy, Inc.*, 157 FERC ¶ 61,211, 61,731 (emphasis in original).

5. On September 17, 2018 Cherokee formed a valid LEO with DEC by conveying its legally binding commitment to sell its output to DEC. Cherokee did so by 1) submitting to DEC its notice of commitment form, 2) providing evidence of self-certification via its FERC form 556 certification, and 3) having received a CPCN for the Cherokee facility.

6. On December 12, 2018 Cherokee formed a valid LEO with by conveying its legally binding commitment to sell its output to DEP. Cherokee did so by 1) submitting to DEP its notice of commitment form, 2) providing evidence of self-certification via its FERC form 556 certification, and 3) having received a CPCN for the Cherokee facility.

7. Cherokee's LEO with DEP did not undercut its LEO with DEC because Cherokee's letters to Mr. Keen made clear that "Cherokee is indifferent as to whether or not it 'puts' its energy and capacity to DEP, DEC, or both." Confidential Hearing Exhibit 12, p. 28.

8. Cherokee's communications with Duke in 2018 demonstrate that Cherokee's actions in attempting to negotiate avoided cost rates were reasonable, consistent with the only avoided cost order applicable to cogeneration facilities that requires such rates to be negotiated under PURPA (Order No. 2016-349), and consistent with FERC's concept of a LEO.

B. Cherokee's Avoided Cost Rates

9. Cherokee calculated its proposed avoided cost rates based upon projections of avoided costs at the time of its LEO, in September 2018.

10. Based on its LEO, Cherokee proposed an avoided capacity rate of $47 per kW-year, reflecting the Commission-approved DEC rates that incorporate projected avoided capacity costs, and the avoided energy rate component of $63 per kW-year, for a total rate of $110/kW-year. The energy rate component included $20 per kW-year for "start up" costs. The energy rate component is based upon DEC's September 2018 projections of avoided costs that underlie its October 31, 2018 offer to Cherokee. Since start up costs are paid for when dispatched, along with other variable dispatch costs, the fixed payment calculated by Cherokee is $90/kW-year.

11. Cherokee's avoided cost rate methodology for determining its proposed avoided capacity rate component and energy rate component is based on avoided cost projections as of the date of its LEO. Cherokee's September 2020 negotiated offer reflected lower avoided costs than Cherokee's calculations presented in this docket.

C. Form of Cherokee/Duke Contract

12. The Cherokee Facility has provided all of its electric output to DEC for over two decades.

13. The 2012 Agreement between Cherokee and DEC was a dispatchable tolling agreement enabling DEC to dispatch the Cherokee unit when it needed it and to provide its own gas supply.

14. Cherokee's September 2018 LEO utilized a dispatchable tolling agreement structure, similar to the structure of the 2012 Agreement.

15. DEC's October 31, 2018 rate proposal utilized a "must run" form contract used for intermittent resources, and did not utilize a dispatchable tolling agreement structure.

16. DEC did not propose a dispatchable tolling agreement in writing until February 2021.

D. Duke's Avoided Cost Rate Proposals

17. Duke's October 8, 2018 response to Cherokee's September 2018 LEO contained no avoided cost rates and denied that a LEO existed.

18. Duke's October 31, 2018 letter provided a rate sheet that contained no capacity rate component, but contained an on-peak and an off-peak energy rate.

19. The Duke October 31, 2018 letter provided rate sheets but no supporting documentation as to how the on-peak and off-peak energy rates were calculated, nor any explanation as to why no capacity rate component was included. DEC provided no gas curves or other key avoided cost input assumptions to enable Cherokee the ability to assess the accuracy of Duke's energy rates. Duke's June 14, 2019 letter similarly lacked the relevant backup data requested in order to assess Duke's calculations, which had not been approved or reviewed by this Commission. For a long-term contract with a facility of this size, it is essential for both counterparties to perform due diligence around the pricing of the transaction.

20. It was not until discovery responses were provided after the complaint was filed that Duke provided any gas curves or other details to justify the rates in its October 31, 2018 letter.

21. After its October 31, 2018 letter with unsupported rate sheets, Duke's only offers were based on avoided cost rates in effect as of the date the offers were made; not based on the date of Cherokee's LEO.

22. The DEC rates offered in Sept. 2020 and Feb. 2021 were based on non-transparent and inconsistent assumptions and flawed data, and thus are not just and reasonable nor consistent with PURPA.

23. Cherokee has proposed that in the event the Commission does not determine that the Cherokee proposed avoided cost rate is appropriate in this case because a LEO was not formed, that the Cherokee September 2020 offer of $ 87.45 per kW-year for 2021 (plus start up costs) is the appropriate avoided cost rate to be utilized in a new 10 year dispatchable tolling agreement between Cherokee and DEC. This rate corrects the inherent biases in DEC's modeling of the value of Cherokee's output.

E. Good Faith Negotiation

24. DEC's October 31, 2018 Offer Did Not Contain "Commercially Reasonable Terms" for the Facility.

25. Subsequent to the DEC October 2018 Offer, Cherokee Negotiated with DEC, and DEC Failed to Observe Reasonable Commercial Standards of Fair Dealing.

26. Cherokee's Actions Evidenced Continuing Active Negotiations in Good Faith.

F. True-Up and Overpayment During Extensions of the PPA

27. A true-up of the rates charged and paid pursuant to the existing PPA during the extensions to the PPA granted by the Commission in this Docket is appropriate, and the parties shall calculate appropriate true-up amounts and Cherokee shall refund any overpayment amounts as set forth herein.

VI. EVIDENCE AND CONCLUSIONS

A. Legally Enforceable Obligation

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 1-8

The evidence in support of these findings of fact is found in the pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

<u>Summary of the Evidence</u>

Cherokee Witness Hanson's testimony explains that Cherokee has a right to elect payments under PURPA under one of two avoided cost calculations, at Cherokee's election: "1) avoided costs calculated at the time the LEO is incurred; or 2) avoided costs calculated at the time of delivery." Hanson Direct Testimony, p. 9; Tr. Vol. 1, p. 15.9. Witness Hanson explained that Cherokee elected the first option: to have its avoided costs calculated at the time the LEO was incurred. Mr. Hanson stated that the parties have a historical practice of initiating negotiations "well before" a PPA is executed. Hanson Direct Testimony, p. 12; Tr. Vol. 1, p. 15.12. Mr. Hanson, supported by Witness Strunk, explained that contracting in advance allows the utility to actually avoid capacity additions, in order to defer investments and avoid costs. Hanson Direct Testimony, p. 13; Tr. Vol. 1, p. 15.13; Strunk Direct Testimony, p. 4; Tr. Vol. 1, pp. 126.6, 13-14. Witness Strunk and Witness Hanson both established that Duke was offering capacity payments through 2018 in its standard offer avoided cost rate. Hanson Testimony, p. 14; Tr. Vol. 1, p. 15.14; Strunk Testimony, p. 5; Tr. Vol. 1, p. 126.7.

The record shows that Cherokee communicated its commitment to sell its output to Duke first be its Notice of Commitment and LEO dated September 17, 2018. The record further shows that by letter dated October 8, 2018, Mr. Keen refused to acknowledge Cherokee's LEO, and noted that it would provide its avoided costs later, which Mr. Keen did by letter dated October 31, 2018.[6] Cherokee also communicated its commitment to sell its output to Duke, through bidding into DEP's capacity solicitation, at the express direction of Mr. Keen; and by LEO to DEP dated December 12, 2018. As noted above, the QF's commitment to the electric utility is what triggers the electric utility's commitment to buy from the QF. As Mr. Hanson explained, Mr. Keen (a business development manager who testified that he does not follow the FERC rules and regulations) (Tr. Vol. 2, p. 302) responded to each Notice of Commitment and accompanying

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[6] As discussed in section VI (D) below, DEC enclosed a rate sheet, with no back up data or calculations supporting the rate sheets.

documentation by denying that Cherokee had formed a LEO. *See* Hearing Exhibit 13, Confidential Keen Direct Exhibit 2.. As Mr. Hanson further explained, despite Cherokee's request to clarify what information Duke believed it would need in the event Duke did not believe a LEO had been formed, DEC offered no response, but continued to deny the existence of a LEO. Cherokee continued to negotiate contract pricing under the applicable avoided cost order at the time. Order No. 2016-349, which provides: "All *rates* for QFs above two MW, or otherwise ineligible for the standard tariffs, ***shall be negotiated*** under the Public Utility Regulatory Policies Act of 1978 and the Federal Energy Regulatory Commission's implementing regulations." Yet Mr. Keen confirmed at hearing his view that Duke "can't negotiate avoided costs." Tr. Vol. 2, p. 265.

Rather than commitments to sell, Mr. Keen characterizes Cherokee's communications to sell its output to Duke as unsolicited offers, and attempts to "negotiate rates higher than the Companies' actual avoided costs…." Tr. Vol. 2, p. 242.9. Witness Keen testified that, as a threshold matter, the NOC was available only for QFs two MWs or less, and was thus not "applicable to very large cogeneration QFs like Cherokee; thus Duke would not recognize it." Tr. Vol. 2, p. 242.11. Nevertheless, Mr. Keen communicated to Cherokee that it would "negotiate in good faith" towards a new PPA, (*Id*.) and on October 31, 2018, Mr. Keen sent a letter to LS Power offering a must-take non-dispatchable PPA with a 5 year term and zeroes for capacity payments.

In further argument that Cherokee did not have a LEO established, Mr. Keen faulted Cherokee for 1) responding to DEC's offer with an "unsolicited term sheet" rather than attempting to negotiate based on the PPA Mr. Keen provided, and alleged that the pricing was well-above DEC's avoided costs; 2) submitting a bid into DEP's market solicitation, and 3) subsequently submitting LEO materials to DEP on December 12, 2018. Tr. Vol. 2, p. 242.9. Mr. Keen suggested at hearing that these three actions of attempting to sell power to Duke undercut Cherokee's stated commitments. Tr. Vol. 2, p. 242.12-13. Mr. Keen testified as much, notwithstanding evidence on the record that 1) Cherokee's communications with respect to all three actions were directed to Mr. Keen himself (*See* Hearing Exhibit 13, Confidential Keen Direct Exhibit 2, Attachment 2), 2) Cherokee participated in DEP's solicitation at Duke's invitation (Hanson Testimony, p. 15; Tr. Vol. 1, p. 15.15), and 3) Cherokee clearly communicated in each LEO letter that it was indifferent to the PPA offtaker and would be content if DEP, DEC, or both took Cherokee's output—in other words, rather than attempt to double commit capacity as Mr. Keen and Mr. Snider testified, Cherokee did not care whether DEP or DEC was the buyer. *See* Hearing Exhibit 13, Confidential Keen Direct Exhibit 2, Attachment 2. But it was clear that Cherokee was committing its full output to Duke, not any other off-taker.

Mr. Keen's own exhibit showed that Mr. Keen understood very well that Cherokee did not intend to sell the same capacity to two different companies, and that Mr. Keen himself was communicating in a dual role on behalf of both DEC and DEP without distinguishing between the two. For example, Mr. Keen's June 14, 2019 letter purports to respond to Cherokee's information requests on behalf of both DEC and DEP–even to detailed questions about rate development , and even without specifying whether the answers pertained to DEC, DEP, or both utilities. Hearing Exhibit 13, Confidential Keen Direct Exhibit 2, Attachment 12, pp. 50-51. "Thank you for your request for additional information concerning the avoided cost calculations for DEC and DEP…").

Mr. Keen also faults Cherokee for various gaps in the negotiation timeline, suggesting that the gaps did not evidence commitment. However, the record shows that Mr. Keen's June 14, 2019 letter was entirely unresponsive to Cherokee's request for "supporting calculations," "backup information," and "supporting data" to support the avoided cost calculations that Duke had provided, such that Mr. Keen had to have known that Cherokee could not verify any of Duke's calculations based on the limited and high level rate design information that Mr. Keen provided apparently on behalf of DEC and DEP jointly. *See* Hearing Exhibit 13, Confidential Keen Direct Exhibit 2, Attachments 10-12, pp. 44-51. Despite Cherokee having made clear requests to each company for avoided cost calculation information, Mr. Keen responded with a vague joint response without even differentiating as to inputs requested between the two companies, DEP and DEC. This thwarted the due diligence process that Mr. Strunk described as critical to the transaction. *See* Tr. Vol. 3, p. 295.

The record further shows that after the October 31, 2018 rate sheets were sent to Cherokee, none of the subsequent avoided cost offers sent by DEP or DEC were based on the projected rates as of the date of Cherokee's LEO. Instead, they reflected current avoided costs as of the date of the offer. See Tr. Vol. 3, p. 596. Duke witness Mr. Freund testified at the hearing that after he calculated the avoided cost rates that were sent in DEC's October 31, 2018 letter, he was never asked again to re-look at or otherwise review the rates calculated at the time of the LEO. *See* Tr. Vol. 2, p. 354.

At hearing, Commissioner Belser questioned Mr. Keen, asking "What would Cherokee have to have provided to Duke to establish a LEO in Duke's opinion?" Tr. Vol. 2, p. 299. Mr. Keen clarified that he believed a LEO required a "binding obligation" that "both the counterparties can count on, so it would have to have been some [type] of an executed document … In other words, a letter agreement that both parties signed establishing it." *Id*. In response to further questioning, Mr. Keen stated that an email would have been acceptable, but "all they had to do was accept those avoided costs…" Tr. Vol. 2, p. 300. Testimony from Witness Bowman, Witness Snider and Witness Freund confirmed that the avoided costs that Duke provided were offered on a take-it-or-leave it basis with no room for negotiation as each believed that Duke had no ability to negotiate rates. Mr. Keen further noted that there would have to be "an agreement that an obligation had been established…" Tr. Vol. 2, p. 303-4. Ms. Bowman similarly testified that Cherokee's LEO claim is precluded by "rejecting each of the Companies' repeated offers of avoided cost rates…" Tr. Vol. 3, p. 502.23; Direct Testimony, p. 23., and suggests that Cherokee's maintenance of its market-based tariff to maintain "the option" for third party sales (via FERC proceedings from early 2021) similarly demonstrated a lack of commitment. Tr. Vol. 3, p. 502.24.

Mr. Snider's testimony agrees with Mr. Keen that a LEO was not established, but acknowledged that FERC's LEO concept is "intended to protect QF's right to sell power to a utility under PURPA where the utility refuses to enter into a contract or the QF and utility cannot agree on PPA terms and conditions." Tr. Vol. 2, p. 392. Mr. Snider agreed with Mr. Keen that Duke would not recognize the LEO form with respect to Cherokee, but instead described "how a large QF like Cherokee would establish a LEO and commit to sell their power to DEC or DEP in South Carolina." Tr. Vol. 2, p. 393.

Mr. Snider and Witness Bowman both describe this "standardized process" they use with Large QFs like Cherokee, rather than the NOC form, to form a Large QF LEO. *See* Tr. Vol. 2, p. 393; *see also* Tr. Vol. 3, p. 502.22. As Mr. Snider described it--a "standardized process for negotiating a PPA" which included pricing valid "normally for about 60 days" and a PPA. *See* Tr. Vol. 2, p. 393. Mr. Snider described that the LEO would then be formed "[o]nce the parties reach full agreement on all of the PPA terms and conditions, the PPA is executed by the QF..." Tr. Vol.

2, p. 393-94. Mr. Snider stated that this execution of the PPA "thereby memorializes the QF's LEO to commence delivering power to the utility." Tr. Vol. 2, p. 394. In response to questions, Mr. Snider acknowledged that Cherokee had communicated its "intent" to commit its power to Duke, but he did not acknowledge an actual commitment. Tr. Vol. 2, pp. 394, 414-15. Witness Bowman agreed with Witnesses Keen and Snider that no LEO had been created. However, Ms. Bowman's direct testimony recognizes that the QF's actions can and do bind the utility: "[u] nder FERC's regulations, the LEO evinces a commitment by the QF to "deliver energy and capacity to a utility over a specified term" *and thereby* obligates the utility to purchase its power in the absence of a mutually-binding contract." (emphasis added) Tr. Vol. 3, p. 502.19. She further testified at the hearing that it is the QF's choice, not the utility's, to decide whether to have its avoided cost rate based on projected costs at the time of the LEO or based on avoided cost rates at the time of delivery. *See* Tr. Vol. 3, p. 504-505 (Answering "Yes, that's what I said in my summary and in my testimony." to "And you noted also that it's the QF[']s option to have its avoided-cost rates based on either at the time the power is delivered or prior to the commencement of the term at the time the obligation is incurred, correct?"); *see also* Bowman Hearing Exhibit No. 18 (Duke response to Cherokee discovery request no. 2-1). Ms. Bowman further testified that it is the SC Commission—not the utility—who decides whether a LEO is created, (Tr. Vol. 3, p. 506-507; Bowman Hearing Exhibit No. 18 (Duke response to Cherokee discovery request no. 2-1)), and acknowledged that "the utility does not have a right to unilaterally revoke or nullify a QF's LEO." Tr. Vol. 3, p. 506. When questioned by Commissioner Belser whether it is Duke's position that a contract is required to form a LEO, Ms. Bowman stated that "I think there are some states that require a signed contract in order for a LEO to be created," but that FERC typically defers to the states. Tr. Vol. 3, p. 526.

Both Witness Bowman and Mr. Hanson point out new rules in Order No. 872 that provide for a financial viability requirement for QFs to form a LEO. While Ms. Bowman acknowledged that these new rules "are more directly applicable to new QF capacity versus QFs that are operating today," (Tr. Vol. 3, p. 502.21), Mr. Hanson testified this financial viability requirement plainly does not apply to existing QFs; and in any case, Cherokee has demonstrated such viability. As Mr. Hanson testified, FERC explained that the viability requirement "will protect QFs against onerous requirements for a LEO that hinder financing, such as a requirement for a utility's execution of an interconnection agreement or power purchase agreement, or requiring that QFs file a formal complaint with the state commission, or limiting LEOs to only those QFs capable of supplying firm power, or requiring the QF to be able to deliver power in 90 days." Hanson Rebuttal, 15; Tr. Vol. 3, p. 660.15.

On rebuttal, Mr. Hanson refuted Duke's witness claims that a LEO was never created. Mr. Hanson stated that while Duke did "respond" to Cherokee's requests, its refusal to: "1) recognize Cherokee's LEO date and the rights created on that date, 2) acknowledge the history of its relationship with Cherokee and the Facility, or 3) provide support for its proposed rates, have prevented open and meaningful negotiations required by PURPA and the orders of this Commission." Hanson Rebuttal Testimony, p. 2; Tr. Vol. 3, p. 660.2. Mr. Hanson clarified his reasoning for waiting until late in negotiations before filing a complaint: litigation is expensive, and Cherokee is mindful of litigation expenses and the resources of this Commission. Tr. Vol. 3, pp. 691-92. Mr. Hanson explained that, given the order to negotiate rates, he understood that negotiating avoided cost rates rather than 1) ceding to litigation, or 2) accepting rates below avoided cost; was prudent and consistent with this Commission's directives. Tr. Vol. 3, pp. 691-92

At hearing, Mr. Hanson explained the history of the LEO as intending to prevent gamesmanship—utilities did not want to contract with third parties because it was more profitable for utilities to build their own. Tr. Vol. 3, p. 679. Consistent with Mr. Snider's testimony regarding the economics of PURPA, Mr. Hanson explained this is because the utility gets to increase their rate base and earn returns on that," (Tr. Vol. 3, p. 679) as opposed to the straight passthrough of costs for PURPA contracts explained by witness Snider.

Commission Determination

Based on the evidence, we recognize that Cherokee formed a LEO with DEC as of September 17, 2018; and as a result, Cherokee is entitled to avoided cost rates projected for the delivery period as of September 17, 2018. It is apparent based on the testimony of Duke's witnesses that the key individuals responsible for Duke's PURPA implementation misapprehended PURPA's requirements and this Commission's implementation thereof. As a result, Duke did not comply with PURPA. Instead, Duke refused to negotiate avoided cost rates with Cherokee under PURPA as this Commission required as of September 17, 2018, and misapprehended FERC's LEO requirements under PURPA by describing a vague and onerous process for Cherokee to form a LEO (or no path at all). From the very beginning, even before DEC provided its avoided cost rates to Cherokee in response to its September 27 LEO, Mr. Keen rejected Cherokee's LEO, by letter dated October 8, 2018. While Duke points to the Notice of Commitment subsequently sent to DEP as evidence that Cherokee was not actually committing its output to DEC in September 2018, that event occurred after Mr. Keen's October 8, 2018 letter. Thus, Duke rejected Cherokee's LEO from the very beginning, and its subsequent conduct undermined the LEO by Duke providing offers not based on projected costs at the time of the LEO. In addition, Cherokee was very clear it was offering its output to Duke—whether DEP or DEC, or both—and it was not offered to anyone else during that time. Mr. Keen's course of conduct in responding to Cherokee on behalf of DEC and DEP without differentiating between the two demonstrates there was no confusion about the desired offtaker based on Cherokee's communications.

Under PURPA and as Duke witness Bowman acknowledged, it is the QF's right, not the utility's, to determine whether to establish a LEO, and thus to have its rates based on avoided costs projected at the time of the LEO, or at the time of delivery. Bowman Testimony, p. 23; Tr., Vol. 3, p. 504. The Commission further determines that Duke unilaterally rescinded Cherokee's original LEO, in violation of PURPA, and contrary to Duke's own witnesses that a utility has no unilateral right to nullify or rescind a QF's LEO. As noted above, Duke Witness Mr. Freund testified at the hearing that he was never again asked to re-look or review the avoided cost rates provided to Cherokee in October 2018, around the time of Cherokee's LEO. See Tr. Vol. 2, p. 354. Subsequent offers were based on current costs at time of the offer, not based on projected rates at the time of the LEO. Duke's last offer—in February 2021—also used current avoided cost rates, which would be "time of delivery rates" since the 2012 Agreement expired at the end of 2020. The Commission determines that Duke's tactics further undermined PURPA by pushing Cherokee now into avoided cost rates at the time of delivery, thereby undermining the clear right under PURPA of a QF to have its avoided cost rates based on rates at the time of its LEO, or at the time of delivery. 18 C.F.R. § 292.304(d)(1)(ii).

As Witness Bowman seemed to recognize, but other Duke witnesses did not, FERC has made clear that "a QF, *by committing itself to sell to an electric utility,* also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations." *JD Wind 1, LLC*, 129 FERC ¶ 61,148, 61,633 (2009) (emphasis added). FERC has given deference to "the states to determine the date on which a legally enforceable obligation is incurred" and "such deference is subject to the terms of the Commission's regulations." *Cedar Creek*, 137 FERC ¶ 61,006 at P 35 & n.57 (citing *W. Penn Power Co.*, 71 FERC ¶ 61,153 at 61,495) (1995); *see Deseret Generation & Transmission Coop., Inc.*, 175 FERC ¶ 61,041, n. 28 (2021). As Commissioner Ervin observed at hearing, a LEO "doesn't require a meeting of the minds." Tr. Vol. 1, p 111. Indeed, FERC has found that, as part of those parameters provided by FERC, states cannot require a utility's agreement in order to recognize a LEO:

> "just as requiring a QF to have a utility-executed contract, such as a PPA, in order to have a legally enforceable obligation is inconsistent with PURPA and our regulations, requiring a QF to tender an executed interconnection agreement is equally inconsistent with PURPA and our regulations. Such a requirement allows the utility to control whether and when a legally enforceable obligation exists – e.g., by delaying the facilities study or by delaying the tendering by the utility to the QF of an executable interconnection agreement. Thus, the Montana Commission's legally enforceable obligation standard is inconsistent with PURPA and our regulations under PURPA." *See FLS Energy*, Inc., 157 FERC ¶ 61,211, 61, 730 (2016).

However, the evidence set forth above reveals that each Duke witness that testified regarding LEO requirements got FERC's LEO requirements wrong. Both Ms. Bowman and Mr. Snider describe how Duke recognizes a LEO with large QFs like Cherokee (*See* Tr. Vol. 2, p. 393; *see also* Tr. Vol. 3, p. 502.22.): that "standardized process" simply describes the negotiation and execution of a PPA. Ms. Bowman apparently believes that states are permitted to require a utility-signed agreement to form a LEO. All three Duke witnesses who testified to the LEO; but most troublingly, Mr. Keen who directed the negotiations; signal that the QF is *required* to accept Duke's take-it-or-leave-it avoided cost offers in order for a LEO to have been created. We recognize that the purpose for locking in rates at the time of the LEO is to protect a QF's right to properly calculated avoided costs—it would be illogical to require a QF to agree to avoided cost rates as a pre-requisite to forming a LEO. The purpose of the non-contractual LEO, as FERC set forth in Order No. 69, is "to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility." Order No. 69, 45 Fed. Reg. at 12,224 (1980). Under questioning from Commissioners, no Duke witness acknowledged a scenario where Cherokee could have created a LEO *without* Duke's agreement, or where Cherokee's commitment could bind Duke, as FERC requires. We find this view was mistaken.

Duke's witnesses also fault Cherokee for tailoring a Commission-approved form that Duke had posted for small QFs in order to support Cherokee's commitment to sell its output pursuant to a LEO; again, pointing to their standardized process for *executing a PPA*. However, as Mr. Snider recognized, Cherokee did so to convey its "intent" to commit its power. Tr. Vol. 2, pp. 394, 414-15. Further, as a matter of logic, it is unclear why a small QF—one eligible for standard rates that do not require negotiation—would have to clear such a low bar to avail itself of a LEO, a simple form; where a QF like Cherokee that was required to negotiate rates would be required to accept Duke's unilaterally calculated rates in order for a LEO to be recognized. Such a concept would turn PURPA and the LEO requirement on its head.

We further find that Duke's refusal to negotiate rates with Cherokee further misinformed its understanding of its obligations before this Commission, including its failure to recognize the LEO that Cherokee formed in September of 2018.[7] We found Mr. Hanson credible and his reliance on the then-effective avoided cost order, which required large QF rates to be negotiated under PURPA, to be reasonable. Duke's wholesale refusal to do so, and claims that *it could not negotiate rates under PURPA*, are troubling not only because they violate the Commission's order, but because Duke's memorandum of law characterized this Commission's directive as a simply "procedural" order, and attempts to rely on orders issued 1) in other utilities' individual avoided cost dockets, 2) on orders issued in other states, and 3) on orders inapplicable to Cherokee. *See* Post-Hearing Legal Brief of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC (stating "The barebones, procedural nature of Order No. 2016-349 does not supersede the Commission's earlier PURPA-implementation orders approving zero capacity credits and, most significantly, the Commission's earlier PURPA-implementation orders approving zero capacity credits and, most

[7] Duke's obstructive conduct, however, was not limited to communication about negotiated rates. Specifically, Duke had also taken the position during discussions about a potential deal with DEP, that neither Cherokee as a QF nor a firm PPA for purchase of Cherokee's output could be designated as a network resource under the Joint OATT. This is completely inconsistent with FERC precedent, where FERC has found that firm, non-curtailable PPAs can be designated as network resources. See Order no. 890A, where FERC reiterated its conclusion in Order No. 890, that firm, non-curtailable PPAs can be designated as network resources. Order No. 890A, 73 Fed. Reg. at 3084. DEP would thus be able to designate a PPA with Cherokee—which would be non-curtailable—as a network resource, enabling DEP to import power from the DEC zone. Instead, besides not agreeing that such a PPA could be designated as a network resource, Duke also said that Cherokee would have to pay for point to point transmission service in order to transmit the output from Cherokee in DEC to DEP. This would result in a pancaked rate, inconsistent with FERC policy, and Duke's own commitment made to FERC when it sought approval of the DEC/DEP merger. *See* Hanson Direct testimony at pp. 17-18; Tr. Vol. 1, pp. 15.17-18; and Hanson Rebuttal Testimony at p. 14 & Exhibits 2 and 3, Tr. Vol. 3, p. 660.14 (showing a number of QFs and PPAs with QFs designated as network resources under other FERC-regulated utilities).

significantly, the Commission's detailed review and approval of DEC's and DEP's application of the peaker methodology in Order No. 2019-881(A)."). So characterizing this order as a merely ministerial order, Duke proceeded to violate the Commission's mandate as well as the underlying settlement that Duke agreed to before this Commission.

We further determine that Order No. 2016-349 is the only avoided cost order, among the South Carolina orders Duke cited, that includes cogeneration in its directives—applying to *all QFs over 2 MW*, rather than "small power producers" that were addressed in Order No. 2019-881-A. While Duke's briefing suggests that Cherokee falls under this Commission's regulatory definition of "Large QF," we note that Cherokee is not a "small power producer", and per Mr. Keen's testimony, is actually unique on Duke's South Carolina system as a fully dispatchable cogeneration QF. See Tr. Vol. 2, p. 303. Even if 2019-881-A were issued before Cherokee created its LEO, we are not convinced that order factored in Cherokee's unique characteristics as a dispatchable generator, or reflected the unique characteristics that Commissioner Ervin noted—namely that Cherokee could in fact help Duke avoid financing new plants to the ratepayers' benefit. *See* Vol. 1, p., 110 (Witness Hanson responding "I do." to "Do you think that so that you can provide those resources without having Duke have to go out and borrow money and build a new facility, do you think that's something that should be taken into consideration in your favor?"). Duke's continued arguments that a LEO is contingent on Cherokee accepting avoided cost pricing that is 1) inconsistent with Order No. 2016-349 and 2) reflects none of the reliability benefits, are unsuccessful. We further note that our jurisdiction extends not only to PURPA implementation, but also to retail ratepayer costs, and we question whether Duke's decision to build its own dispatchable gas capacity rather than contract with Cherokee—an existing facility that Duke dispatches as economic 60 percent of the time--was prudent and in the ratepayers' interest.

We further find that Cherokee acted reasonably in making itself available to negotiated business arrangements with either DEP, DEC, or both. We recognize that QF output can be split between two different utilities, and it was prudent for Cherokee to allow Duke flexibility in negotiations. Duke's inflexible approach to PURPA implementation and misapprehension of its responsibilities under this Commission's precedent notwithstanding, we find that Cherokee's repeated attempts to put power to the same individual working for both companies only evidences Cherokee's commitment to put power to Duke. We find that Duke's references to Cherokee's 2021 reactive power proceeding are taken out of context and in any case inapposite, as Cherokee clearly stated it wanted to maintain the "option" to engage in non-PURPA sales. In fact, we find that maintaining this option was particularly prudent given Duke's failure to negotiate under the requirements of Order No. 2016-349.

Consistent with the foregoing and the evidence presented in the record, we recognize that Cherokee formed a LEO with DEC as of September 17, 2018; and as a result, Cherokee is entitled to avoided cost rates projected for the delivery period as of September 17, 2018.

B. Cherokee's Avoided Cost Rates

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 9-11

The evidence in support of these findings of fact is found in the pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

Summary of the Evidence

Mr. Strunk testified that his calculations of Cherokee's avoided cost rates for capacity and energy were based on projected rates at the time of the LEO consistent with PURPA. Strunk, Testimony, p. 5; Tr. Vol. 1, p. 126.7. He further testifies that Duke did not, in 2018 or anytime thereafter, up to and including the hearing, submit rates for 2018 based on the use of a dispatchable tolling agreement with capacity payments. Strunk Testimony, p. 11-12; Tr. Vol. 1, pp. 126.13-14. Only after the hearing, at the Commission's request, did Duke submit a rate with capacity payment and utilized a dispatchable tolling agreement instead of a must-run agreement. *See* Tr. Vol. 2, p. 384-85; *see also* Duke Energy Carolinas, LLC's and Duke Energy Progress, LLC's Corrected Late-Filed Exhibit 1.

Mr. Strunk calculated an appropriate $/kW-year rate by adding the value of Cherokee's energy and the value of its capacity. Strunk Testimony, pp. 16-17, 19-20; Tr. Vol. 1, pp. 126.18-19, 21-22. As Mr. Strunk testified, to determine the energy value, he relied upon DEC's own offer to compensate Cherokee for energy, which relied upon the September 2018 standard QF modeling run that DEC had performed. Strunk Testimony, p. 16; Tr. Vol. 1, p. 126.19. Witness Strunk simply assumed that the energy rates in DEC's October 31, 2018 offer were consistent with DEC's forecasted avoided energy costs at that time, as required by PURPA. Strunk, Testimony pp. 15, 19-20; Tr. Vol. 1, pp. 126.17, 21-22. Witness Strunk lined up the on-peak and off-peak avoided energy rates with a projection of Cherokee's 2021 output, then calculated the energy value (over and above the cost of dispatching Cherokee) and, consistent with PURPA, expressed that result as a $/kW-year payment as compensation for DEC's avoided energy costs. Strunk, Testimony, pp. 19-20; Tr. Vol. 1, pp. 126.21-22. As Mr. Strunk testified, he used the peak and off-peak fixed

MWH energy rates offered by DEC in October 2018, and converted them to annual compensation of $63 per kW-year.[8] Adding the Capacity component of $47 per kW-year results in the total of $110 per kW-year, inclusive of start up costs. Strunk Testimony, p. 16; Tr. Vol. 1, pp. 126.18, 132; Tr. Vol. 3, pp. 648-49.

Mr. Strunk testified that the October 31, 2018 proposal from DEC only contained a rate sheet—specifically, it included an on-peak and an off-peak energy rate (with no back up support showing the calculation of such rates), but no capacity rate. *See* Strunk Testimony, p. 11; Tr. Vol. 1, p. 126.13. Moreover, Mr. Strunk noted that DEC provided no back up at all to show either (i) how Duke calculated the proposed energy rates, or (ii) why Duke believed it was not obligated to pay Cherokee for capacity, as it had done for the past two decades under PURPA. Strunk Direct Testimony, p. 11; Tr. Vol. 1, p. 126.13.

Duke witness Freund reduced Mr. Strunk's total avoided cost rate of $110 per kW-year by $32 per kW-year, based on Duke's contention that Cherokee was owed no capacity compensation at all for years when DEC does not have a capacity need, because Duke would not be avoiding any capacity costs at all by purchasing power from Cherokee. Tr. Vol. 2, pp. 338.14, 359. Mr. Strunk testified that Cherokee's avoided capacity payment methodology corrects this Duke misconception that Cherokee's capacity rate should have been zero at the time of DEC's October 31, 2018 offer

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8 Mr. Freund reduced the $63 per kW-year amount to take out start up costs, because he noted such costs are paid for separately and should not be part of the avoided cost rate paid to the QF. But Mr. Freund noted that he does not dispute that QFs with dispatchable tolling agreements should be paid for start up costs as that reflects industry practice. Tr. Vol. 2, pp. 338.11, 357. Mr. Freund also noted that his re-calculation of Mr. Strunk's avoided cost calculations recognized capacity in the years 2028-2030, and he determined a $ 15 per kW-year capacity rate. However, if he utilized a first capacity need in 2026—per the Commission's 2019 avoided cost rate order—that would add two more years of capacity and result in a capacity rate of $ 36 per kW-year. See Tr. Vol. 2 at 357, 359, 366 and 368.

letter. Strunk Direct Testimony, pp. 19-20; Tr. Vol. 1, pp. 126.21-22. Specifically, Mr. Strunk stated that he included compensation for avoided capacity costs, as the existing rates being offered to QFs at that time incorporated compensation for capacity, and Cherokee had been providing reliable capacity to the DEC system for decades. Strunk Testimony, pp. 4-5; Tr. Vol. 1, pp. 126.6-7. Witness Strunk states that he sourced the capacity value from DEC's Schedule PP tariff to assure non-discrimination. Strunk Direct Testimony, p. 16; Tr. Vol. 1, p. 126.16. When Cherokee established a LEO in September of 2018, the Schedule PP tariff was the only capacity rate for QFs that was approved by the Public Service Commission of South Carolina (via Order 2016-349). Because the per unit value of avoided capacity costs does not change with respect to the size of the QF, Witness Strunk testified that it was appropriate to carry over that avoided capacity cost rate from the small QF tariff to the large QF rate available to Cherokee. Tr. Vol. 3, p. 602, 606-607. Mr. Strunk took dollar per MWh rates in this tariff and applied them to a projection of Cherokee's 2021 MWh output to arrive at the capacity revenues for Cherokee. This approach resulted in a capacity rate that appropriately implements PURPA since it: (1) relies on the most recent commission order at the time Cherokee established its LEO, and (2) provides compensation for Cherokee's reliable capacity that can supplant DEC investment, as intended by PURPA.

As Mr. Strunk also testified, Order 2016-349, controlling precedent in October 2018 when DEC provided its rate schedule, included rates that were based on full capacity compensation payments for QFs, and were not discounted to reflect years without a purported capacity need. Tr. Vol. 1, p. 172. Only after Cherokee's LEO, after the passage of the Energy Freedom Act, did IRPs formally require Commission approval, and only in the 2019 avoided cost docket did the Commission confirm the nexus between the IRP and the avoided cost calculations. Mr. Strunk noted that the DEC IRP approval process has proven to be particularly contentious for DEC in recent years, as evidenced by their ongoing 2020 IRP approval proceeding with this Commission wherein the Commission identified major substantive flaws with Duke's most recent IRPs. Tr. Vol. 1, p. 189**.** Mr. Strunk also noted that the avoided cost review processes undertaken by the Commission are similarly contentious, underscoring the need to rely on values that have been explicitly approved by the Commission in the absence of an alternative diligence process. Tr. Vol. 3, p. 637**.** In response to questions from Commissioner Caston, Mr. Strunk highlighted that in docketed proceedings, the avoided cost forecast input assumptions are subjected to due diligence by the parties to the case. *See* Tr. Vol. 1, p. 172. But Mr. Strunk pointed out that when Duke does the modeling itself in the context of an update, there is no assurance that the input assumptions are reasonable unless the QF itself can perform its own diligence. See Tr. Vol. 3, p. 635 ("And when you heard Ms. Hipp from ORS, she said, 'Okay, we reviewed the assumptions. We reviewed all the assumptions in the avoided-cost docket,' but she doesn't review the assumptions that go into the updates, and there's been no scrutiny of the assumptions. And I think that's one of the big issues, because they require a lot of discretion on the part of whoever's doing the modeling.").

Commission Determination

Based on the Commission's determination in Section VI (A), above, that Cherokee's Sept. 2018 commitment letter was a valid LEO, the avoided cost rate for this facility shall be the $ 110 per kW-year amount, though if start up costs are reimbursed separately, as they are in the 2012 Agreement, the rate would be $90 per kW-year. The Commission thereby incorporates by reference the evidence and conclusions referenced above in the LEO section of this Order (Section VI-A). Moreover, the only evidence in the record that is probative and consistent with PURPA is the avoided cost rate calculations performed by Mr. Strunk based on projected rates at the time of Cherokee's LEO in September 2018. DEC's conclusion that no capacity was owed to Cherokee is based on flawed assumptions and treatment of Cherokee as if it were an intermittent resource, which would be owed no capacity and would be paid for energy per a "must-run" contract. It was appropriate for Mr. Strunk to have used cost inputs approved by the Commission in his calculations of the avoided cost rate for Cherokee, including capacity prices approved in 2016 for DEC's standard offer QF rates as specified in Schedule PP. Additional support for the Cherokee calculated avoided cost rates is discussed below in the "Form of Contract" section, which discusses further the support for a capacity rate given the ability to dispatch the Cherokee facility by DEC and to reduce fuel cost risk by utilizing a tolling agreement structure.

C. Form of Cherokee/Duke Contract

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 12-16

The evidence in support of these findings of fact is found in the pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

Summary of the Evidence

Cherokee contends that Duke's failure to incorporate the fully dispatchable operational feature of the Cherokee plant in its offers violated PURPA and ignored the two decades of reliable, dispatchable power provided by Cherokee, including service under the dispatchable tolling agreement structure of the 2012 Agreement, and service under the initial agreement. *See* Hanson Direct Testimony, p. 17-18; Tr. Vol. 1, p. 15.17-18. Duke characterizes the initial agreement between DEC and Cherokee as "must-take". *See* Tr. Vol. 2, pp. 245, 263, (stating on p. 263 "This power plant, as I think I mentioned, had operated under a must-take agreement for many years prior to this one.”). Cherokee has countered that that the initial must-take agreement did not provide sufficient dispatch flexibility. As a result, in 2001, DEC and Cherokee voluntarily modified the must-take agreement to include dispatch provisions. Tr. Vol. 1, p. 197. Hence, DEC has been dispatching the Cherokee facility for two decades. Mr. Keen’s characterization of that initial agreement as must-take leaves out essential information, specifically the fact that the must-take clause was amended with provisions for dispatch in the year 2001. (*See* Tr. Vol. 3, pp. 679-680; *See* also Tr. Vol. 1, p. 197 (where Witness Strunk testifies: “But it’s certainly unreasonable from my perspective that given the course of dealing between Cherokee and Duke where – since 2001 that facility’s been dispatchable, that Duke would want to turn that backwards and create this nondispatchable must-take agreement.”).

Cherokee has pointed out that where an avoided cost rate is not based on a standard offer, the state commission is required to take into account certain factors for purchases, including “ability of the utility to dispatch the qualifying facility, the “expected or demonstrated reliability of the qualifying facility,” and certain contractual or LEO terms, including “the duration of the obligation.” *See* 18 C.F.R. § 292.304(e)(2)(ii)(A-C). As Mr. Strunk stated in his direct testimony, “The Cherokee facility is a cogeneration QF that is fully dispatchable by Duke whenever it calls upon it, thereby providing reliable capacity to the grid. Cherokee’s dispatchability sets it apart from intermittent solar or wind QFs that cannot be dispatched.” Strunk Testimony, pp. 4-5; Tr. Vol. 1, pp. 126.6-7.

Cherokee further asserts that by offering energy only rates, a “must run” non-dispatchable contract and no capacity payment, Duke violated PURPA by ignoring these attributes of the

Cherokee facility that were not just possible features on paper, but actual operational attributes of the Cherokee facility relied upon by Duke. See Strunk Rebuttal Testimony, p. 6; Tr. Vol. 3, p. 598.6. Cherokee has explained that it would not be a symbol of favoritism to offer rates/contract terms different from intermittent wind or solar facilities, but instead application of clear provisions in FERC regulations with regard to attributes of a particular QF that the Commission must take into account in determining an avoided cost rate.

Cherokee witness Mr. Strunk states that he took into account the dispatchable nature of the Cherokee facility. Mr. Strunk testified that DEC's customers would not be well served by a must-take agreement that embeds inefficiencies into DEC's dispatch. Strunk Direct Testimony, p. 14; Tr. Vol. 1, p. 126.16. (DEC and Cherokee agreed to abandon such a structure in 2001 when they added dispatchability provisions to the initial Cherokee contract.) Mr. Strunk testified that in order to reflect Cherokee's dispatchability, and consistent with the existing contract, that he structured the payments on a $/kW-year basis, consistent with the parties' existing contract and consistent with the PURPA requirement to account for the facility's dispatchability. Strunk Direct Testimony, p. 16; Tr. Vol. 1, p. 126.18.

In addition, Duke Witness Mr. Keen testified that he was looking out for the ratepayers by offering a "must run contract". Tr. Vol. 2, pp. 278-79, 287-88. As Mr. Strunk noted in response, such a "must run" contract is appropriate for intermittent resources such as solar or wind facilities, but certainly not for a fully dispatchable generation plant such as Cherokee's cogeneration plant. *See* Tr. Vol. 3, pp. 591-593; Strunk Testimony, p. p-8, Tr. Vol. 3, pp 598.6-8. Mr. Strunk further testified that contrary to Mr. Keen's assertions, the "must-run" contract offered by DEC on October 31, 2018, on a take-it-or-leave-it basis, was not in the best interests of DEC's customers.

As Mr. Strunk testified, such a "must-run" contract embeds "rigidities and inefficiencies that result in higher fuel costs for Duke's customers." Tr. Vol. 3, p. 591. As Mr. Strunk further noted, such "must-run" or "must take" contracts could result in incurrence of millions of dollars of unnecessary fuel costs, which would flow through to ratepayers through the Duke fuel cost rider. *Id.* Mr. Strunk also pointed out that when Cherokee's dispatch cost is below the PPA price, but above the costs of Duke's other resources, Duke's fuel costs will be unreasonably high, to the detriment of ratepayers. *Id*. at 592. Having a dispatchable tolling agreement structure is far more preferable, enabling DEC to control when the plant is dispatched in light of related fuel costs and the costs of other Duke resources. Strunk Testimony, p. 14; Tr. Vol. 1, p. 126.16 ("Many utilities have found themselves holding QF contracts struck at a forecast avoided cost rates that did not anticipate the subsequent gas price declines that actually occurred. A tolling agreement structure mitigates the risk to DEC customers that the energy from Cherokee will be out of market due to gas price changes.").

Mr. Keen also testified that the contract length was an area where Duke had some flexibility to negotiate with larges QFs like Cherokee. Tr. Vol. 2, p. 247. Similarly, the dispatch provisions would fall under the types of "terms and conditions" that Duke had the flexibility to negotiate under PURPA. *See* Tr. Vol. 2, p. 266 (where Mr. Keen stated "negotiations would be something like the terms and conditions in the PPA."). But Mr. Strunk pointed out that Duke did the opposite, by not negotiating on the length of the PPA and not offering dispatchable contract terms in writing until after Cherokee had filed its complaint. Mr. Strunk testified that Duke took a take it or leave it approach, by not offering capacity payments and offering only "must run" contracts, as would be appropriate for a non-dispatchable, intermittent resource like solar or wind facilities Tr. Vol 3, p. 592.

Commission Determination

Based on the evidence, the Commission determines that Duke and DEC in particular violated PURPA by completely ignoring, and failing to take into account, operating attributes of the Cherokee facility that distinguished it from other QFs, as required by PURPA. Specifically, under PURPA, where an avoided cost rate is not based on a standard offer, the state commission is required to take into account certain factors for the avoided cost rates and terms for purchases from QFs, including "ability of the utility to dispatch the qualifying facility, the "expected or demonstrated reliability of the qualifying facility," and certain contractual or LEO terms, including "the duration of the obligation." *See* 18 C.F.R. § 292.304(e)(2)(ii)(A-C). By offering a "must-run" contract, with no capacity payment, Duke treated the Cherokee facility like an intermittent resource, as Duke Witness Keen acknowledged on the witness stand.[9] Duke's October 31, 2018 proposed "must run" agreement ignored the Cherokee Facility's dispatchability; its demonstrated reliability after providing electric power to DEC for over two decades or the planned 10 year duration of the Cherokee's new or amended contract with DEC.

It is not just desirable under, but in fact mandated by, PURPA, that such characteristics be taken into account with regard to the appropriate avoided cost rate and terms and conditions of

9 Keen asserts that DEC offered all large QFs at that time the same contracts regardless of their characteristics. Keen Cross Examination, Tr. Vol. 2, p. 264-265 (Answering "During that time frame, the 2018 time frame, we were offering must-take agreements to all QFs above two megawatts." to "Is it your testimony that PURPA requires Duke Energy Carolinas to treat every large QF exactly the same whether or not it is a dispatchable natural gas facility or a intermittent solar facility or a wind facility?").

service. In light of these PURPA requirements, DEC violated PURPA by failing to take into account the dispatchability, the reliability, and the duration of the contractual commitment associated with the Cherokee facility in determining appropriate avoided cost rates in response to Cherokee's LEO..

The Commission further determines that DEC was not "looking out for ratepayers" by offering "must-run" contracts to Cherokee, where Duke would have no ability to dispatch the facility or control its fuel costs like it can under a tolling agreement. Instead, as Cherokee Witness Strunk testified, "must-run" contracts would require the facility to be run even at times when its costs exceed those of other Duke resources and Duke would not have control over the costs of fuel, both such risks would be much better controlled under a dispatchable tolling agreement structure. See S.C. Code Ann. § 58-41-20(A) (emphasizing the importance of "reduc[ing] the risk placed on the using and consumer public.").

D. Duke Avoided Cost Rate Proposals

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 17-23

The evidence in support of these findings of fact is found in the pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

<u>Summary of the Evidence</u>

Duke Witness Mr. Freund provided a chart summarizing certain attributes of avoided cost rate offers made by either DEP or DEC. Tr., Vol. 2, p. 338.5. Three of those offers (DEC Oct. 2018, DEP Feb. 2019 and DEP June 2020) were for non-dispatchable agreements. See Tr., Vol.

2, p. 338.5, figure 1. The DEC Sept. 2020 offer was for a dispatchable tolling agreement but it was an oral offer and Mr. Freund had no knowledge whether that offer was ever provided in writing. Tr. Vol. 2, pp. 347-48. The DEC Feb. 2021 offer was submitted after the Complaint was filed in this proceeding. Only the DEC Sept. 2020 oral offer and the DEC Feb. 2021 offer were for 10 year, dispatchable tolling agreements. Tr., Vol. 2, p. 338.5, figure 1; Tr., Vol. 2, pp. 347-48. Mr. Freund's chart did not include the actual rates offered under each of the five offers summarized in his chart. (such rates were subsequently provided by Duke at the direction of the Commission and included in a post-hearing exhibit dated August, 6, 2021 (Late-Filed Exhibit 1)), although Mr. Freund's sworn testimony at hearing was that the "one thing that's missing" (Tr. Vol. 2, p. 385) required to produce the Table requested by Chairman Williams was the energy valuation of Cherokee as of September 2018. Apparently, for that reason Mr. Freund relied upon Mr. Strunk's estimate of $43/kW-year (Tr. Vol. 2, p. 383). Hence, Cherokee questions the validity and reasonableness of the rate DEC purports to correspond to a forecast avoided cost rate for a dispatchable tolling agreement at the time of Cherokee's LEO.

Mr. Freund also noted that the first year of capacity need was 2026 for both the DEC Sept. 2020 and DEC Feb. 2021 offers, while 2028 was used for the DEC Oct. 2018 Offer. Tr., Vol. 2, p. 338.5, figure 1; Tr. Vol. 2, p. 349. Mr. Freund also used August 2020 gas cost assumptions for the DEC Feb. 2021 offer. Tr., Vol. 2, p. 338.5, figure 1; Tr. Vol. 2, p. 353.

Duke witness Keen discussed the negotiations between Cherokee and DEP and DEC. He also provided some information regarding Duke's offers. *See* Tr. Vol. 2, pp. 242.4, 242.9-12; and Confidential DEC/DEP Keen Direct Testimony Exhibits 1, 2.

Mr. Hanson provided the following table (Table 1) in his Rebuttal regarding Cherokee's view of the deficiencies of Duke's offers. Hanson Testimony, p. 8; Tr. Vol. 3, p. 660.8.

Table 1: Timeline of Offers

Date	Offered by	Deficiencies
October 31, 2018	Duke Energy Carolinas	– Did not appropriately take into account the dispatchability of the Cherokee facility. – Discriminatory; did not provide compensation for avoided capacity costs. (See Strunk Rebuttal, p.11). – Inconsistent with Order 2016-349 and FERC's Implementing Regulations. (See Strunk Rebuttal).
February 1, 2019	Duke Energy Progress	– The transmission arrangements were not offered in a manner consistent with DEC and DEP's merger commitments. – Did not appropriately take into account the dispatchability of the Cherokee facility.
June 24, 2020	Duke Energy Progress	– Included avoided cost rates, but on terms that ran contrary to those approved in Order 2020-315(A). – Offered a form PPA appropriate for a solar QF and inappropriate for a dispatchable facility like Cherokee. – Disputed the establishment of a LEO.
December 15, 2020	Duke Energy Carolinas	– Offered an "as available" contract. – Failed to provide contract rates until after the delivery of energy to Duke such that Cherokee would have no idea whether its plant would be economic to run.
February 10, 2021	Duke Energy	– Apparently took dispatchability into account, but: – Avoided energy costs were not aligned with the Cherokee LEO date. – Avoided capacity costs were not aligned with the Cherokee LEO date.

Mr. Strunk testified that the post-October 31, 2018 rates offered by DEC or DEP were not based on projected costs as of the date of Cherokee's LEO, and virtually all were based on wrong structures for the Cherokee facility. Mr. Strunk has testified about these flaws and problems with Duke's avoided cost offers. *See* Strunk Rebuttal Testimony, p. 3-8; Tr. Vol. 3, pp. 598.3-8. In particular, post-October 31, 2018, Duke offered avoided cost rates based on current projections of avoided costs, not projected avoided costs at the time of Cherokee's LEO, as required by PURPA. Under PURPA, it is the QF's choice, not the utility's, to base its avoided cost rates on (i) avoided cost rates at time of delivery or (ii) projections of future avoided costs as of the LEO date. *See* Strunk Rebuttal, p. 3-4; Tr. Vol. 3, pp. 598.3-4; *see also* 18 C.F.R. § 292.304(d)(1). As also discussed in section VI (C) above, Mr. Strunk testified that it is not Duke's right to negate Cherokee's LEO by setting arbitrary deadlines (like the 60 day take it or leave it deadline), and refuse to provide adequate back up data and information in order for a QF to assess whether the avoided cost rates were determined accurately. Strunk Rebuttal, p. 4; Tr. Vol. 3, p. 598.4. For a transaction of this size, it is essential that both parties perform due diligence.

The individual DEC rates are further discussed below, as they were provided through Duke's Late-Filed Exhibit 1. To assure a complete record included in one document, information from Cherokee's comments on Duke's Late Filed Exhibit are set forth below in this Proposed Order. However, Cherokee has not included material that Duke seeks to strike under its recently filed Motion to Strike, except where there is record evidence supporting the statements below.

Mr. Strunk's $110/kW year tolling agreement rate ("DEC 2018 Strunk") includes compensation for start costs. Tr. Vol. 1, p. 132. Mr. Freund did not provide DEC's offers inclusive of start costs because he noted on cross-examination that it is customary for DEC to pay start costs separately. Tr. Vol. 2, pp. 356-357. In order for DEC Late-Filed Table 1 to provide apples-to-apples information to the Commission, it must remove start costs, approximately $20/kW-year, from Mr. Strunk's $110/kW-year tolling agreement rate. The resulting "DEC 2018 Strunk" rate for comparison purposes is $90/kW-year. In addition, Mr. Strunk testified that he used DEC's September 2018 modeling to determine the appropriate 10-year tolling agreement rate. *See* Strunk Rebuttal, p. 16; Tr. Vol. 3, p. 598.16.

DEC Oct 31, 2018 OFFER

As Cherokee noted in its Comments on the Duke Late Filed Exhibit, the DEC Oct 2018 pricing shown by Duke in the Late Filed Exhibit has the following problems.

A. Understates Energy Value. The energy valuation provided by Duke for "DEC Oct 2018" should not be relied upon by the Commission as it is patently inconsistent with DEC's September 2018 avoided cost modeling results and falls below even the $43/kW-year estimated presented by Mr. Strunk and adopted for comparison purposes by Mr. Freund. Mr. Freund, DEC's witness supporting its avoided cost rates, relied on Mr. Strunk's estimate of energy value and testified that he did not have an energy valuation performed by Duke for Cherokee as a dispatchable facility using assumptions for October 2018. (Tr. Vol. 2, p. 385) Mr. Strunk clarified in Rebuttal Testimony that the $43/kW-year estimate was conservative and that an explicit valuation of Cherokee's dispatchability would result in a higher avoided cost rate. (pp. 13-14 of Mr. Strunk's pre-filed rebuttal).

B. Not an actual offer. For purposes of clarification, the "DEC Oct 2018" column in Late Filed Exhibit 1 was not DEC's avoided cost rate proposal to Cherokee in October of 2018. Instead, and as indicated in Late-Filed Exhibit One, the "DEC Oct 2018" column includes "the avoided cost components for a 10-year dispatchable tolling PPA capacity rate" that had been given to the ORS in response to a data request made in this Docket. *See* Late-Filed Exhibit 1. DEC did not offer Cherokee a 10-year dispatchable tolling Power Purchase Agreement ("PPA") in October of 2018. Instead, on October 31, 2018 DEC offered Cherokee a "must-take" PPA with a 5-year term, with energy-only rates (no compensation of capacity value), despite the fact that the existing PPA between DEC and Cherokee was a dispatchable tolling agreement with a 7.-year term, and despite the fact that the parties had operated under a dispatchable arrangement beginning in 2001. (In 2001 DEC and Cherokee voluntarily modified the unworkable must-take agreement to make it dispatchable.)

DEC Sept 2020

As Cherokee noted in its Comments on the Late-Filed Duke Exhibit, the DEC Sept 2020 rate shown in the Late Filed Exhibit has the following problems.

A. **Ignores PURPA-mandated LEO.** DEC based its September 17, 2020 verbal offer on pricing information available as of September 2020, including a capacity need date taken from DEC's 2020 IRP. This approach incorrectly ignored the fact that Cherokee sent a letter of commitment to put capacity to DEC in September 2018 and has provided Duke with dispatchable energy for two decades. *See* Sections VI-A-B, *supra.*

B. Misleadingly construed as a lower offer. In a note in Late-Filed Exhibit 1, DEC suggests that its September 2020 offer is in fact more or less equivalent to its much lower February 2021 offer, due to a purported difference in start costs. *See* Late-Filed exhibit 1. Yet, DEC provides no evidence that the September 2020 offer (a verbal offer) had different start cost terms than its other offers. The Commission should view DEC's characterization of the

September 2020 offer with skepticism. As noted at the hearing, the new tolling agreement rate will be substantially (*i.e.*, approximately 24%) below the existing tolling agreement rate. See Tr. Vol. 3, p. 627-28.

C. Verbal offer. Duke provided Cherokee with a verbal offer, forcing all parties in this proceeding to rely on figures that are not easily verifiable by the Public Service Commission of South Carolina. Tr. Vol. 2, pp. 347-48.

D. Does not consider Cherokee counteroffer. Cherokee countered with an offer ($87.45 /kW-year) in response to DEC's September 2020 offer. *See* Cherokee Comments on DEC/DEP Late Filed Exhibit One. Cherokee was responding to Duke's consistent understatement of the Cherokee valuation. The counteroffer provides a more reasonable rate than the one presented by DEC, should the Commission elect to use September 2020 as the avoided cost valuation date.

Cherokee in its Comments on the Duke Late Filed Exhibit also noted that the DEC Feb. 2021 offer provided by Duke has the following problems:

A. Stale gas costs. Duke's modeling also uses stale gas prices that artificially lower the avoided cost payments owed to Cherokee under PURPA. *See* Cherokee Comments on DEC/DEP Late Filed Exhibit One, p. 10. Duke uses gas prices from August of 2020, out of sync with both Cherokee's LEO date of September 2018 and with the purported time of Duke modeling (February 2021). *Id*. As DEC is well aware, forward gas prices were significantly higher as of Cherokee's LEO date in September of 2018 than in August of 2020, leading to artificially low avoided costs as the base of DEC's February 2021 offer. *See* Tr. Vol. 3, p. 636 ("[T]hat offer was based on gas prices as of August 20[20], so now we're looking at gas prices that are about a year stale."). Mr. Freund also noted in his direct testimony and during cross-examination that he used

August 2020 gas assumptions for the February 2021 offer. Tr., Vol. 2, p. 338.5, figure 1; Tr. Vol. 3, p. 353.

B. Ignores PURPA-Mandated LEO. DEC based its February 10, 2021 offer on pricing information available as of February 2021, including a capacity need date taken from DEC's 2020 IRP. This approach again incorrectly ignores the fact that Cherokee had put capacity to DEC as early as September 2018 and has provided Duke with dispatchable energy for years. *See* Cherokee Comments on DEC/DEP Late Filed Exhibit One, p. 10. In addition, now that the 2012 Agreement has expired, and continues on an interim basis, Duke's delaying tactics have thrust Cherokee into time of delivery rates, rather than rates projected at the time of the LEO. Duke has in effect taken away from Cherokee one of the key rights of a QF—to base its rates upon the time of the LEO or at the time of delivery.

C. Not reflective of current avoided costs. Gas prices are now higher than those relied upon by DEC in establishing the February 2021 offer. If the Commission does not find that Cherokee established a LEO in 2018, then the avoided cost rates should be set on more current data than is reflected in the August 2020 gas curves used by DEC in valuing avoided costs for the February 2021 offer. A more current avoided cost forecast will be higher with current gas curves, all else equal. *See* Cherokee Comments on DEC/DEP Late Filed Exhibit One, p. 10.

Chart 1 below presents applicable $/kW-year rates for Cherokee consistent with DEC's estimates of avoided costs as of the date of Cherokee's LEO and compares them with various DEC offers. For completeness, Chart 1 includes DEC's September 2020 and February 2021 offers, but we stress that these offers understate the applicable avoided cost rate for Cherokee and are not based on DEC's avoided costs as of the 2018 LEO. In addition, the February 2021 offer undervalued Cherokee's energy output. At the hearing, Mr. Strunk testified that the DEC 2021 offer was based on unreasonable assumptions that lead to valuations of Cherokee's energy output that are too low. *See* Tr. Vol. 3, p. 636-37, where Mr. Strunk explained: "in response to counsel for Duke — I talked about how the modeling of the gas price for Cherokee, that underlies the offer, was based on a different gas hub than had been used for Cherokee previously, and a different gas hub than had been referenced in the contract. And that gas hub that was used in that modeling tends to have a higher price, and the use of a higher gas price would tend to depress the energy value that Cherokee provides to the Duke system." As such, the rates shown under the DEC rubric should not be interpreted by the Commission to represent rates that fully reflect the then-applicable avoided cost forecasts.

Chart 1: Avoided Cost Rates Using NERA and DEC Methodologies

Avoided Cost Component	Units	DEC October 2018 (Strunk Testimony)	DEC September 2020	DEC February 2021 Adjusted
Energy	$/kW-year	$43.00	$39.01	$31.44
Capacity	$/kW-year	$47.00	$35.68	$35.68
Total	**$/kW-year**	**$90.00**	**$74.69**	**$67.12**

1. NERA's calculated avoided energy value for October 2018 ($63/kW-year) was reduced by $20/kW-year, the approximate value of start costs as calculated by Duke Witness Freund. *See* Tr. Vol. 2, p. 338.13. This allows NERA's figures to be presented on an apples-to-apples basis with the other offers.

2. The $43/kW-year avoided energy value for October 2018 provides a conservative estimate of the avoided energy valuation applicable to Cherokee in an October 2018 tolling agreement. As noted in Mr. Strunk's pre-filed rebuttal testimony, accounting for dispatchability will necessarily raise the valuation. See Strunk Rebuttal, pp. 14; Tr. Vol. 3, pp. 598.14 (where he explains: "The absence of explicit modeling of Cherokee's actual dispatch flexibility makes my analysis conservative. Incorporating flexibility could only increase the calculated value of Cherokee to the DEC system, all else equal."

3. The adjusted value reflects NERA's partial correction of the DEC modeling, which addresses the inappropriate switching of the gas hub by DEC. See Tr. Vol. 3, pp. 636-37. We note that DEC did not object to the inclusion of this adjusted data in the record.

Cherokee's September 2020 Offer

Mr. Hanson also testified regarding Cherokee's Sept. 2020 offer of $ 87.45 per kW-year for 2021, to be utilized in a 10 year dispatchable tolling agreement, with start up costs to be paid in addition to the $ 87.45 per kW-year which was a counter to the DEC Sept. 2020 oral offer. *See* Tr. Vol. 3, p. 685-86. The capacity and energy rates each escalate after 2021. Hearing Exhibit 13, Confidential Keen Direct Exhibit 2, Attachment 2, Att. 18, p. 2 (see attached). As. Mr. Hanson noted, the avoided cost rate based on the LEO of September 2018, was 25 percent less than the current rates under the 2012 Agreement, and the September 2020 rate was even lower, 37 percent less than the current rates under the 2012 Agreement. See Tr. Vol. 3, pp. 677, 686. They are more reflective of accurate avoided cost rate assumptions and calculations determined under PURPA.

<u>Commission Determination</u>

As previously discussed (*See* Section III, *supra*), avoided cost rates must be just and reasonable and in the public interest. Rates based upon avoided costs are deemed to satisfy this standard. However, avoided cost calculations based on inconsistent assumptions, stale data or other flaws cannot be the basis of appropriate avoided cost rates, and thus are not just and reasonable and in the public interest. *See Conn. Light and Power Co.*, 70 FERC ¶ 61,012, 61,023-24 (1995) (citing 18 C.F.R. § 292.304(b)(2) (1994)) (asserting that "a rate for purchases from a [QF] will be considered to be just and reasonable and in the public interest and also not discriminatory 'if the rate equals…avoided costs'."); *See also S. Cal. Edison Co.*, 70 FERC ¶ 61,215, 61,676 (1995) (stating "We believe it is inconsistent with our obligation under PURPA to ensure just and reasonable rates, and our goals to encourage development of competitive bulk power markets, to permit the use of PURPA to create new contracts that do not reflect market conditions for new bulk power supplies.”).

In light of the Evidence summarized above, we determine that none of the Duke avoided cost rate proposals are just and reasonable and in the public interest, as they do not reflect the projected rates at the time of the LEO. The avoided cost rates proposed by Cherokee pursuant to its LEO are consistent with PURPA and are thus just and reasonable and should be adopted. Even if the LEO is not taken into account, the post-2018 rates offered by Duke that were based on non-dispatchable, must run agreementsalso violate PURPA because they failed to take into account the Cherokee facility’s dispatchability; demonstrated reliability and commitment to a 10 year term.

In addition, we reject the February 2021 offer as it was submitted after the Complaint was filed, and it violates PURPA. Specifically, now that the 2012 Agreement has expired, and continues on an interim basis, Duke’s delaying tactics have thrust Cherokee into time of delivery rates, rather than rates projected at the time of the LEO. Duke has in effect taken away from Cherokee one of the key rights of a QF—to base its rates upon the time of the LEO or at the time of delivery. *See* sections VI (A, B), *supra*.

Alternative relief – The Commission finds that while it does not adopt the rates associated with Cherokee’s LEO, for the reasons stated above, we do adopt the September 2020 counter-offer made by Cherokee to Duke, that is discussed in the summary of evidence above. Adopting such rate is within the discretion of the Commission. As the U.S. Supreme Court has stated in Hope Natural Gas v. FERC:

> We held in Federal Power Commission v. Natural Gas Pipeline Co., supra, that the Commission was not bound to the use of any single formula or combination of formulae in determining rates. <u>Its ratemaking function, moreover, involves the making of “pragmatic</u>

adjustments." Id., 315 U. S. 586. (emphasis added) *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 602 (1944).

E. Good Faith Negotiation

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 24

The evidence in support of this finding of fact is found in the pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

Summary of the Evidence

On October 31, 2018, DEC sent Cherokee an offer that included 1) a letter setting out the rates for the draft PPA; and 2) "must-take" draft PPA with a 5-year term and no capacity payment (the "DEC October 2018 Offer). Hearing Exhibit 13, Hearing Exhibit 13, Confidential Keen Direct Exhibit 2, Attachment 4; *see* Tr. Vol. 2, pp. 258-59. The DEC October 2018 Offer contained two rates, consistent with a "must-take" agreement: an "on-peak energy price," and an "off-peak energy price." See Vol. 2, p. 271. The DEC October 2018 Offer also stated that the "avoided cost pricing included in this letter is available until December 31, 2018," for a period of sixty (60) days. Hearing Exhibit 13, Hearing Exhibit 13, Confidential Keen Direct Exhibit 2, Attachment 4.

At the time, Cherokee and DEC were operating under a dispatchable tolling agreement (effective July 1, 2013) with a 7 year term. Tr. Vol. 2, p. 242.7. In addition, Cherokee and DEC had been using a dispatchable relationship in their previous PPA since 2001. Tr. Vol. 1, p. 116. The DEC October 2018 Offer, therefore, ignored 1) the dispatchable tolling agreement form under which the parties were operating and had been operating for nearly two decades; and 2) the 7 year term of the current PPA. Tr. Vol. 1, p. 118. Further, the rates proposed by DEC were based on a "must-take" agreement, and were not appropriate for a dispatchable cogeneration Facility like Cherokee. Tr. Vol. 1, pp. 116-118.

In addition, the DEC October 2018 Offer did not contemplate any negotiation by the parties, as evidenced by the language in Mr. Keen's letter to Cherokee: "If you desire to proceed with this transaction please include the seller's contact information and complete exhibits 1, 4, and 5." Hearing Exhibit 13, Confidential Keen Direct Exhibit 2, Attachment 4. In refusing to negotiate rates, Duke violated Order No. 2016-349 which provides: "All rates for QFs above two MW, or otherwise ineligible for the standard tariffs, shall be negotiated under the Public Utility Regulatory Policies Act of 1978 and the Federal Energy Regulatory Commission's implementing regulations." Order No. 2016-349.

In response, Duke argues that at the time (Fall of 2018), DEC was "offering must-take agreements to all large QFs" based on the proposition that "under PURPA you're supposed to treat everybody kind of fairly and the same." Tr. Vol. 2, p. 263. Accordingly, DEC provided the same "must-take" draft PPA (a five-year term, no capacity payment, and a 60-day window for avoided cost pricing) to each QF requesting a PPA from DEC. In other words, the rates and terms of the DEC October 2018 Offer were "commercially reasonable" because those rates and terms were provided uniformly to all QFs, and did not take into account dispatchability and other characteristics required under FERC's regulations. *See* 18 C.F.R. § 304(e). This is a drastically different course of conduct by Duke which, as Mr. Hanson testified, had negotiated both terms and price for 2012 PPA. *See* Tr. Vol. 1, p. 22. Mr. Keen testified in response to Commissioner Belser that he was unaware of another large dispatchable QF on Duke's system in South Carolina and he was not aware of another cogeneration QF in South Carolina. Tr. Vol 2, p. 303.

Commission Determination

The "must-take" form of PPA, a five-year term, and proposed rates that were based on a "must-take" agreement, simply were not "commercially reasonable" for the Cherokee Facility, based on the way the parties were and had been operating, based on the risks of a "must take" agreement that are shifted to Duke's ratepayers, and based on the specific characteristics of the Facility known to DEC. The Duke Companies have cited to no provision in PURPA that required or would require DEC to offer Cherokee this "must-take PPA." Significantly for negotiation purposes, DEC gave no explanation to Cherokee why DEC chose to depart from the dispatchable tolling agreement form used in the PPA. Additionally, the language in Mr. Keen's letter to Cherokee ("If you desire to proceed with this transaction, please include the seller's [Cherokee's] contact information and complete exhibits 1, 4, and 5" (Hearing Exhibit 13, Confidential Keen Direct Exhibit 2, Attachment 4)) evidences that DEC did not contemplate that *any* negotiation of its proposal would take place in violation of Order No. 2016-349.

Moreover, coupling those terms with a sixty-day window for negotiation was simply unreasonable for Cherokee. As the record of this case demonstrates, well more than sixty days passed before DEC offered Cherokee a dispatchable tolling agreement. *See* Hearing Exhibit 5. In fact, more than two years passed and the complaint proceeding was imminent before DEC provided Cherokee with written offer proposing that form of PPA.

While the Commission understands DEC's efforts to provide a uniform offer to *similarly situated* QFs, that policy does not mandate or even allow DEC to overlook the characteristics of the Cherokee Facility and DEC's history with that Cherokee Facility as mandated under PURPA. Apparently overwhelmed with requests from non-cogeneration QFs, DEC reversed its prior course of dealing with Cherokee from engaging in robust negotiations with Cherokee on an individual basis in 2012, to a take-it-or-leave-it approach. DEC knew all the reasons why a five-year "must-take" PPA was inappropriate for Cherokee. It was not commercially reasonable to require Cherokee to accept the DEC October 2018 Offer or to operate under an assumption that it could not negotiate avoided costs when the relevant South Carolina Commission order at the time *required* it to negotiate avoided costs. Similarly, it was not commercially reasonable for DEC to refuse to recognize the dispatchable tolling agreement arrangement currently and historically employed by DEC and Cherokee.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDING OF FACT NO. 25

The evidence in support of this finding of fact is found in the pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding. Subsequent to the DEC October 2018 Offer, Cherokee Negotiated with DEC, and DEC Failed to Observe Reasonable Commercial Standards of Fair Dealing.

Summary of the Evidence

On December 12, 2018, in response to the DEC October 2018 Offer, Cherokee sent DEC a "Summary of Major Business Terms and Conditions for Tolling Agreement" ("Cherokee December 2018 Counteroffer"). Hearing Exhibit 13, Confidential Keen Direct Exhibit 2, Attachment 5. As set out therein, Cherokee proposed a tolling agreement with a 7-year term "utilizing the existing contract between the parties" (Id.) as a framework, and offered a pricing structure based on a dispatchable tolling agreement. Consistent with a dispatchable tolling agreement, Cherokee proposed a pricing structure with different components than the DEC October 2018 Offer.

On December 21, 2018, DEC responded to the Cherokee December 2018 Counteroffer, asserting that the rates offered by Cherokee were not consistent with DEC's avoided costs, and claiming that DEC did not have a capacity need. (Hearing Exhibit 13, Confidential Keen Direct Exhibit 2, Attachment 8).. DEC's response did not acknowledge or address Cherokee's proposal to use a dispatchable tolling agreement. Nor did DEC's response provide any pricing based on a dispatchable tolling agreement. In other words, DEC refused to negotiate those proposed terms, as confirmed by multiple witnesses' testimonies, and gave no justification for its failure to do so.

Duke characterizes the Cherokee December 2018 Counteroffer as "unsolicited" (Keen Testimony), and submitted by Cherokee "rather than engaging in negotiations regarding the PPA that I provided on behalf of DEC . . . ." Tr Vol. 2, p. 242.12. DEC rejected the "unsolicited term sheet as inconsistent with PURPA." (Tr. Vol. 2, p. 242.12).

Commission Determination

Cherokee was actively negotiating a successor PPA. In response to the PPA form, term, and pricing offered by DEC, Cherokee counteroffered with proposals for PPA form (the existing dispatchable tolling agreement), term (7 years), and pricing (charges for capacity, fixed o&m, VOM, start) based on a dispatchable tolling agreement. Proposing the current form of PPA is inarguably "commercially reasonable," as is proposing a term (7 years) similar to that of the current PPA. Contrary to the position of the Duke Companies, Cherokee was not required to negotiate "regarding the PPA" provided by DEC, (Tr. Vol. 2, pp. 242.12) but instead offered an alternative that was not only reasonable, but then existing and structured in a way that protects Duke's customers' from risks associated with changes in fuel prices. Likewise, Cherokee's proposed rates associated with a dispatchable tolling agreement were a commercially reasonable response to proposed pricing predicated on a “must-take” agreement. Moreover, the Cherokee December 2018 Counteroffer was provided to DEC within DEC’s own 60-day negotiation window.

DEC, on the other hand, simply was not observing reasonable commercial standards of fair dealing in its negotiations with Cherokee. Following its receipt of the Cherokee December 2018 Counteroffer, DEC’s response introduced as hearing Exhibit 13 (Hearing Exhibit 13, Confidential Keen Direct Exhibit 2, Attachment 6) again did not recognize the form of PPA under which the parties were operating, refusing to negotiate that issue presented by Cherokee (Tr. Vol. 2, p. 242.14). Similarly, DEC refused to negotiate Cherokee’s pricing proposal, and particularly the specific charges contained in that proposal. DEC rejected the pricing proposed by Cherokee, as it certainly had the right to do. However, DEC’s assertion that the pricing proposed by Cherokee “is well above DEC’s avoided costs we sent you on 10/31/18 . . . .” is not apparent or verifiable. Hearing Exhibit 13, Confidential Keen Direct Exhibit 2, Attachment 8. DEC offered “apples” (on-peak and off-peak energy prices), while Cherokee offered “oranges” (a number of different price components consistent with the contract under which Cherokee was operating at that time, but with updated and, importantly, *reduced* avoided cost rates). Moreover, DEC’s response did not provide Cherokee with its proposed avoided cost rates for the rate components in the Cherokee December 2018 Counteroffer. Finally, DEC continued, without explanation or justification, to offer only a “must-take” agreement and accompanying rates with a five-year term, for almost two years.

In sum, DEC’s unwillingness to acknowledge the existing dispatchable tolling agreement between DEC and Cherokee, as well as its refusal to consider a dispatchable tolling agreement form or negotiate rates associated with a dispatchable tolling agreement represented a commercially unreasonable course of dealing.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NO. 26

The evidence in support of this finding of fact is found in the pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

Summary of the Evidence

Duke makes various claims about the effect of Cherokee's submission in response to a DEP RFP, and submitting a LEO to DEP (Tr. Vol 2, p. 242.14) on its "negotiations" with DEC and Cherokee's LEO. According to Duke, Cherokee could not be "actively" negotiating with DEC while seeking to do business with DEP, and according to the Duke Companies "Cherokee's request to sell its power to DEP superseded the prior negotiations with DEC." (Tr. Vol. 2, p. 242.14). Also, as described above, DEC's correspondence of October 5, 2018, claimed that Cherokee did not establish a LEO because "[a]mong other things, the use of the Notice of Commitment form is limited to qualifying facilities of two (2) MW or less that are eligible for DEC's South Carolina Schedule PP standard offer tariff and is therefore not applicable to the Facility." (Hearing Exhibit 13, Confidential Keen Direct Exhibit 2, Attachment 3)

In response, Cherokee testified that has committed- and provided- energy and capacity to DEC for more than 20 years (Tr. Vol. 3, p. 642). Cherokee points out that all of its communications to DEC and DEP were completely open and transparent: meaning that each communication Cherokee made to one Duke entity was provided at the same time to the other Duke entity. Tr. Vol. 3, p. 642. In fact, Mr. Keen has job functions with both DEP and DEC. Because every "move"

Cherokee made was fully disclosed to both DEC and DEP, Cherokee gained no advantage (unfair or otherwise) in its negotiations with either DEC or DEP.

Similarly, Cherokee made it clear to both DEC and DEP that it was indifferent with respect to where its energy and capacity went within the Duke enterprise. Strunk Rebuttal, p. 7; Tr. Vo. 3, p. 598.7. Cherokee was negotiating with DEC and DEP in order to explore its commercial options, and importantly, to make every effort to avoid the costly and time-consuming litigation that has now ensued. None of those actions, however, compromised its commitment to put power to DEC.

Cherokee also testified that at no time did Cherokee discuss, much less offer, its energy or capacity to any entity other than DEC or DEP.

Commission Determination

The Commission is convinced that Cherokee actively negotiated in good faith throughout the relevant time period. Fundamentally, Duke has provided no evidence that Cherokee's actions provided any negotiating advantage to Cherokee, that Cherokee has sought a rate other than that based on Duke's avoided costs in the fall of 2018, or that Cherokee's actions prejudiced Duke unfairly in any way. While Cherokee openly and transparently pursued options with both DEC and DEP, Cherokee never discussed offering or selling its energy and capacity to *any* entity other than DEC or DEP. As such, Duke employs arguments that Cherokee failed to negotiate actively as a sword (to limit Cherokee's legitimate options), rather than a shield (to prevent Cherokee from "gaming" the system). And, as set forth *infra*, DEC was refusing to acknowledge Cherokee's right to a dispatchable tolling agreement at the very same time DEC claimed Cherokee's entrée to DEP "superseded" any negotiations between Cherokee and DEC.

On the other hand, the Duke Companies' actions stymied continued negotiations, and for no commercially reasonable reason. For example, DEC's claim in its October 5, 2018 correspondence, introduced as Exhibit 4 attachment 3 that Cherokee's September 18, 2018 did not constitute a LEO is curious at best: "[a]mong other things, the use of the Notice of Commitment form is limited to qualifying facilities of two (2) MW or less that are eligible for DEC's South Carolina Schedule PP standard offer tariff and is therefore not applicable to the Facility." (Hearing Exhibit 13, Confidential Keen Direct Exhibit 2, Attachment 3). As DEC conceded at the hearing, Cherokee's use of that particular Notice of Commitment form did not confuse DEC. Tr. Vol. 2, p. 258 . In addition, during the Fall of 2018, DEC *did not have* a Notice of Commitment Form for a large QF like the Cherokee Facility. Tr. Vol. 2, pp. 302-04. Nor did DEC claim that Cherokee did not provide the information necessary for DEC to move forward with the negotiation process. In other words, DEC offered no objection to the substance of Cherokee's communication, but quite literally raised an issue with respect to the *form* in which it was provided. In this regard, given that DEC did not have a NOC form for a large QF, it made perfect sense for Cherokee to use the only other NOC form available given that it includes language approved by the state commission and utilized by Duke.

EVIDENCE AND CONCLUSIONS SUPPORTING FINDINGS OF FACT NOS. 27

The evidence in support of these findings of fact is found in the pleadings, testimony, and exhibits in this Docket, and the entire record in this proceeding.

<u>Summary of the Evidence</u>

The avoided cost rates approved by the Commission in this Order are lower than those being paid by DEC to Cherokee pursuant to the terms of the PPA. As set out in Orders 2020-846 and 2021-294 extending the terms of the PPA, the Commission has reserved "the right to consider whether or not it is appropriate to subject the rates charged and/or paid by any Party" during these extensions to true-up. Order 2020-846, at 2; 2021-294, at 2.

The ORS is in favor of such a true-up, as described in the Testimony of Dawn Hipp (Tr. Vol 3, p 568.6):

> In the event the Commission determines that going forward the price paid by Duke Energy to Cherokee for the power generated by Cherokee is less than the price paid under the 2012 PPA, ORS recommends the dollar amount attributed to the incremental overpayment to Cherokee due to the extension of the terms of the current 2012 PPA be credited or refunded to Duke Energy customers in a manner determined by the Commission.

Likewise, various Duke witnesses testified in favor of any overpayment being refunded or returned to DEC. For example, Duke Witness Keen testified regarding the "expectation that Cherokee will return the overpayment once the applicable new avoided cost rate is set." (Tr. Vol. 2, p. 242.8). In addition, Duke Witness Snider indicated that how DEC collects any such overpayment "would be something we would have some flexibility in." (Tr. Vol. 2, p. 473).

Cherokee witness Hanson agreed that Cherokee would be obligated to "make [customers] whole" based on the Commission's determinations in this Docket (Tr. Vol. 1, p. 100), and suggested that a refund/return could be accomplished in a variety of ways, including incorporating any such amounts "into the forward rate," or a "refund-type mechanism." *Id.*

<u>Commission Determination</u>

As articulated in our previous Orders referenced above, we find that Cherokee should be responsible for the dollar amount attributed to the incremental overpayment to Cherokee due to the extension of the terms of the current 2012 PPA. We therefore direct DEC and Cherokee to confer with respect to the amount of that "incremental overpayment" that took place during the extensions of the PPA. DEC and Cherokee shall also include ORS in their discussions. The new PPA entered into as a result of this Order shall maintain the level of credit support required in the 2012 PPA. The parties shall report back to the Commission within ten (10) days of this Order with both the amount, as well as any proposal or proposals for a credit or refund of the refund amounts.

ORDERING PARAGRAPHS

NOW, THEREFORE, IT IS HEREBY ORDERED THAT:

1. Based upon the testimony, hearing exhibits received into evidence and the entire record of these proceedings, the Commission hereby adopts each and every finding of fact enumerated herein. The Commission's conclusions of law are fully stated above.

2. The parties shall execute a PPA with the rates, terms, and conditions based on the consistent with the conclusions and determinations Such new rates [either the rates based on Cherokee's LEO or the Cherokee Sept 2020 offer] shall take effect commencing September 1, 2012 and ending December 31, 2030. Cherokee and DEC shall determine any differences in the payments made to Cherokee for the January 1, 2012 through August 31, 2021 between the payments under the 2012 Agreement, as extended, and the rates adopted by this Order, and any differences in payment shall be credited from one party to the other over a thirty six (36) month period.

3. The Commission finds the PPA with the rates, terms and conditions ordered herein to be just and reasonable, in the public interest and reflective of DEC's avoided cost rates.

4. Any credit support for the extension of the 2012 Agreement shall be consistent with the 2012 Agreement credit support terms, and shall not exceed any credit support amount therein.

5. This Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

Justin T. Williams, Chairman

ATTEST:

____
Jocelyn Boyd, Chief Clerk